Electric Industry Restructuring and Seattle City Light

Introduction

Utility industry restructuring has been underway in earnest since the early 1990's. The 1992 Energy Policy Act expanded the access that independent power producers would have to utility transmission. The Thatcher government privatized the Central Electricity Generating Board and took steps to create a competitive retail electric system. California seized on this example and began its own experiment in retail competition. By the mid 1990s, virtually every US state legislature had debated this issue, and about half the states – mainly those with higher retail rates – had passed legislation phasing in retail competition.

Similarly, the US Congress from 1994-1998 debated whether retail competition ought to be mandated nationwide. The fight in the House was primarily between Republican supporters of a very rapid transition, and Republican supporters of a slower pace. The Senate was less enthusiastic. However, during this period, many industry participants, including many Washington State utilities, treated retail competition as inevitable and perhaps desirable.

After the 2000-2001 West Coast power crisis, and specifically, the meltdown in California, half a dozen states have backed away from restructuring. Even in the states that continue to pursue this model, performance has lagged far beyond original expectations. Only about 3 percent of retail loads in the US are currently served by non-utility providers. Even in bellwether states like Pennsylvania, many customers that opted for "choice" have returned to the incumbent utility. The merchant plant industry is in serious financial difficulty, having lost five times the market capitalization of the Enron bankruptcy (over $200 billion) in two years. Trade reports indicate that 130,000 megawatts of merchant capacity (roughly 60 percent of total merchant capacity) is for sale.

Nevertheless, in July 2002, the Federal Energy Regulatory Commission issued a Notice of Proposed Rulemaking (NOPR) for a standard energy and transmission market design (SMD) that creates challenges for existing utilities and opportunities for merchants and middlemen.

Drivers of Restructuring and Potential Impacts to City Light

It is important for utilities, and their governing boards, to understand the drivers for restructuring, and potential risks and impacts. The principal driver for restructuring in the mid-1990s was a cheap spot market for electricity, driven by surplus natural gas production capacity, surplus gas pipeline capacity, surplus electric generation, and surplus transmission. In these circumstances, spot markets were deep, liquid, and reasonably transparent – power sold, for the most part, for a small margin above marginal operating costs, meaning natural gas price. This translated into 1.8-2.5 cents/kWh during

1994-1998 in West Coast markets. Average US retail electricity prices during this time were 7.5 cents/kWh, and, while these are not in any way comparable products, large users and challengers (including marketers like Enron) drove the political and legislative debate.

In this environment, with or without legislation, utilities typically take action to cut perceived financial risks. This generally includes sale of generation, whether required by law – as in California – or by financial markets. Many utilities transferred these generating assets to unregulated subsidiaries; others sold them outright. Roughly 12 percent of total US generating capacity has been sold in this fashion, making up about half of total merchant capacity. Long term planning – both for loads and resources – and long term utility investments – in generation, transmission, and conservation – was replaced with increased reliance on the wholesale market and a short term business focus.

A Closer Look at Competition

The implications are best understood with a slightly deeper look at the cost structure of the industry. Two examples – California and Seattle – should suffice.

California two major investor-owned utilities entered restructuring with average retail rates of 11 cents/kWh. Of this rate, roughly 7 cents represented the cost (capital, fuel, operating) cost of existing generation and long term contracts. The remaining 4 cents represented the cost of transmission and distribution. Meanwhile, wholesale electric prices were roughly 2.5 cents, creating a potential "stranded cost" of 4.5 cents/kWh if regulators did not permit recovery of these historical costs.[1] Utilities were allowed to recover these costs, albeit without a rate of return, which permitted an immediate 10 percent reduction in overall rates. When these stranded costs were recovered, the retail rate freeze would be lifted, and retail rates would fluctuate with market price. With minor differences, this approach is used in every retail competition state.

Wholesale market prices, meanwhile, would need to rise to 2.8-3.5 cents/kWh (probably 5 cents at current gas prices) before new capacity was built.[2] It was also understood that prices would be volatile and occasionally high (over 10 cents/kWh for several hundred hours per year) before either annual average would be reached. While 2.8 and 3.5 don't seem too far apart, the latter number required 10 cent/kWh prices for more like 1000 and less like 100 hours per year, with significantly greater risk of political backlash.

During this time, Seattle's average retail rate was 4.2 cents/kWh, of which 2.2 cents covered generating costs and the remainder covered transmission and distribution. We

[1] This, of course, is for one point in time. The amount that might actually be stranded would change with market conditions. When utilities sold their fossil generation, this income accelerated recovery of stranded costs.

[2] In 1997, the range of opinion was narrower (2.8 – argued by the merchants; 3.5 – argued by the skeptics), based on then-current and expected future prices for natural gas. The difference in opinion was mainly driven by assumptions of return requirements, and risks, for new merchant power plants operating without long term power sales contracts. At current gas prices, a 5 cent wholesale market price is probably necessary for merchant investors.

nevertheless faced substantial community pressure, mainly from large industries that saw wholesale market prices in the 2.0-2.5 cent range. Most were extremely surprised, or at least unhappy, to discover the utility's cost structure (2.0 cents for T&D) did not permit much (or any) net savings from retail choice. Wholesale spot price was below our total portfolio cost. Arguably, Seattle customers should not have had much interest in choice, but many did not understand utility cost structure. The situation today (with an additional 2.0 cents from 2000-2001 borrowing) is less clear; we could very well face demands for choice if natural gas was trading at 1994-1999 levels. Costs could be stranded if the utility was required to charge only wholesale market prices.[3]

It may be instructive to think about risks in four different cases:

- New generation is not only cheaper than existing generation, but the combined total (capital, fuel, operating) is cheaper than the operating cost of existing plant. This is rare, but was true in the UK, and restructuring is very tempting. In this environment, many existing units are worthless (e.g., coal in the UK in 1995), lots of new capacity (e.g., gas) is built, old plants are phased out, and the California problem never arises (at least in the short/medium term). Not our situation in the West, and is almost unimaginable for a hydro system with near-zero "fuel" cost.
- New generation (or spot market) is cheaper than your existing portfolio, but costs more than the operating cost of existing plant. This is the case in the West and indeed in most of US. Competition does not imperil existing plants, but utilities generally avoid new investments. Under-building is a big risk. Our current combined 4.3 cent generation cost (loans plus portfolio) is currently cheaper than new generation, but we would be quite vulnerable to industrial customer demands, and potentially, new debates on retail competition, in an environment of low natural gas prices and surplus generating capacity. Moreover, our portfolio cost is overwhelmingly inflexible sunk capital costs.
- New generation (or spot market) is more expensive than your portfolio. Our situation in 1999 (spot was briefly cheaper in 1998), but no longer. No one should pursue retail competition in this world, but the Washington Legislature very nearly passed a bill. Blind to this issue, Montana's Legislature passed a retail competition bill. Utilities in that state sold off their generation at a handsome profit, leaving customers with inevitably higher bills and essentially no recourse. Smart regulators and legislatures should not permit this to happen.
- New generation is cheaper than total retail electric rate. This is the cellular phone example. For the electric industry, the parallel case is self-generation, through fuel cells, microturbines, or small combined cycles. This scenario deserves continuing attention, in part because the marginal cost of new distribution in downtown Seattle is high, and some new loads (e.g., internet

[3] These costs are essentially analogous to the California IOU conditions, though they don't represent any underlying real asset.

hotels or biotech industries) are large users, but not necessarily stable businesses.

Over the long haul, we can probably write off the first and fourth scenarios. We are closer to the third than second scenario. *But it pays to remember that Seattle (and most of the West) passed (at least briefly) through all four scenario conditions between 1998-2001.* As Maura O'Neill pointed out, we ought to be guided by our understanding of long-term costs, benefits, and risks, rather than short term cycles. In that regard, Seattle should focus on a generation portfolio than is demonstrably below the full marginal cost of new resources, and ideally below spot market wholesale price. And Seattle should use the sharpest pencils in evaluating distributed resource investments, and their ability to displace strandable distribution system costs.

Though one might think that the California crisis eliminated any further interest in retail competition, that is not a good long term bet. Pressure for retail competition (and/or "economic development" rates) will arise whenever wholesale spot market prices are below portfolio costs. Markets are not the only driver. Technological change (e.g., fuel cells or other distributed generation), law (e.g., a Supreme Court finding on jurisdictional issues), and regulation (e.g., FERC) can also drive restructuring. Some of these drivers may be indifferent to regional differences.

FERC and Standard Market Design

The principal current restructuring uncertainty involves FERC's proposal for a standard market design.[4] Issued in July 2002, the proposal initially contemplated issuance of a final rule by December 2002. After a strong, early, negative response – primarily from state utility regulators – the schedule slipped to July 2003. Chairman Wood has indicated that he will not proceed with implementation until Congress has completed action on the energy bill. Some features of that bill, if enacted, will substantially impair FERC's ability to implement many elements of the draft proposal. At the same time, as was the case in 2002, the bill extends FERC's level of jurisdictional over federal and other publicly-owned utilities, including Seattle.

A fundamental premise of the NOPR is that vertical integration – joint ownership and operation of generation, transmission, and distribution – constitutes "undue discrimination" under the Federal Power Act. FERC makes this argument (unconvincingly) to justify extending the agency's jurisdiction into many areas historically regulated by states (for IOUs) and local government (for COUs).[5] While the

[4] Two other NOPRs – on standards of conduct for vertically integrated utilities and on generation interconnections at distribution voltages – are also underway, with potentially important impacts to the utility.

[5] FERC's clear jurisdictional authority is over wholesale, interstate private utility transmission of electricity (maybe 10-15 percent of the system) and over wholesale (sale for resale) sales of electricity involving at least one private utility. The agency has never – until SMD – asserted jurisdiction over ALL transmission, over resource adequacy and the prudence of these investment, or over some aspects of retail electric pricing. If these jurisdictional claims go forward (with a final rule), many states will go to court, though it may take years to resolve the issue.

NOPR is long, confusing, and often contradictory, some key elements of SMD pose significant commercial risks for Seattle City Light.

- No priority use of transmission for firm retail customers. Transmission rights (not well defined) may be auctioned to the highest bidder after four years.
- "Locational marginal pricing" for day-ahead and real-time electricity. The RTO-West footprint has about 3000 "nodes," each of which would have a separate price for energy, ultimately changing each five minutes.[6] Price differences between these nodes would drive transmission prices for all energy sales, including those from owned resources or bought under long term contract.
- Resource adequacy standards would be imposed that require utilities to estimate future loads and have sufficient reserves (unused capacity) to exceed demand by at least 12 percent. Regional transmission organizations under FERC jurisdiction would evaluate forecasts and the utility's resource base (including conservation and wind, which may be perceived to have less reliability than natural gas).
- FERC believes strongly in real-time pricing, especially for larger customers, and in the ability of large customers to bid their "saved" kilowatt-hours in regional markets. The NOPR is far from precise in this area; some approaches could create significant retail stranded costs (e.g., when real-time wholesale market costs are low).

Randy Hardy argued that the NOPR is a "dead letter," and, in general, I think I agree. But it is important to keep in mind that despite admitted flaws, the NOPR has not been withdrawn, or amended, or the official schedule (adoption of final rule by July 2003) changed. It is almost certain that any final rule will be significantly different from the draft proposed rule. It is almost certain that no rule will emerge until fall or winter 2003 at the earliest. If the energy bill does not pass, however, FERC may move quickly in directions that are not easy to predict. If the bill passes, and implementation is delayed, we do not avoid the need to address a variety of energy and transmission market features for the Northwest.

Seattle played a formative role in the coalition opposed to standard market design. We continue to staff this effort, and it has been astonishingly successful. Virtually all Republican members of the Senate Energy Committee now oppose SMD. The bill voted out of Committee delays implementation until the day after Chairman Wood's term ends, among other things. Seattle has not been highly visible, however, and there is no evidence that FERC views the utility in a negative light, or in a light any different from other Northwest utilities. That said, some investor-owned utilities that publicly oppose SMD (Entergy, Southern, Progress) have been threatened. Boundary re-licensing may be too distant to link to this issue, but it is not too early to raise the issue.

There are some key internal and external implications.

Planning is harder than ten years ago. Seattle's long term planning process sought a "least-cost" (including environmental factors) resource plan over a 30 year horizon. With

[6] This equates to 31 million different prices for energy and transmission per year, just for RTO West.

California-style restructuring, the models used for this work became instantly outmoded.[7] With other issues looming, five-to-eight years is probably the best horizon to hope for. The strategic framework must go beyond resources to include rates, loads, and transmission and distribution. Some bilateral contracting may be necessary to ensure that our resource and distribution investments are not stranded by potentially volatile loads. We face key decisions on Klamath, South Lake Union, and BPA that ought to be approached with a common framework. Finally, it almost goes without saying that missteps that can tolerated at 4.2 cents/kWh, because of competitive margin, are much more dangerous at 6.3 cents.

Externally, we clearly want a wholesale power market that is robust, liquid, and transparent, to sell into, buy from, and hedge from. Broadly, we had such a market in the West from 1992-1999. Since 2001, utilities have re-built their portfolios (often at great cost, as in California), taking a great amount of volume out of the Western wholesale market. The number of parties active in this market is much smaller, credit risks are higher, transparency is lacking (because bilateral deals predominate), and gas and electric market hubs and indices remain very suspect.[8] The tools to hedge portfolio risk are not what they should be. Absent construction of new generation by either merchant (unlikely) or utilities (more likely, but not easy), this problem will not be easy to fix. In other words, FERC (or a regional transmission organization) cannot easily force more kilowatt-hours to be traded in day-ahead and real-time markets.

California market structure is important to our future, because we are closely interconnected and the market is so large. During 1997-2000, the California Power Exchange (PX) routinely cleared 30,000 megawatts each hour. One hundred MW is cleared in a good hour at either the Mid-Columbia or California-Oregon border. Obviously, the PX – which does not exist today – drove our prices. Market Design-02 is likely to take its place, with potential Northwest impacts that are important, but hard to predict. MD-02, alas, does not resolve the central question of who is responsible – utilities, the state, or merchant generators – for building new generation in advance of dire need. These issues critically affect our ability to buy from, sell into, and hedge risks in western wholesale markets.

The region also needs some resolution, if possible, on BPA's role in resource acquisition and transmission construction. Under the Northwest Power Act, BPA is primarily responsible for all new resources required by regional public utilities. Utilities, on the other hand, don't have the statutory obligation to take whatever BPA acquires. The statutory requirement is politically and economically infeasible. We have not quite figured out a politically acceptable alternative. We are better situated than many regions

[7] These models assume only utility-owned generation, with all wholesale power sold at marginal fuel cost, with retail customers responsible (under traditional regulation) for utility capital costs. Merchant generators must occasionally recover capital costs plus fuel costs, and risks may require a fairly high rate of return. Merchant generators are also under no obligation, in many cases, to operate plants, and may withhold capacity to boost wholesale market price.

[8] On June 13, 2003, FERC issued a staff paper on "the crisis of confidence over the reliability of energy price indices…" given manipulation and false reporting by market participants in recent years, and decisions by individual companies to bar employees from providing such data to industry publications.

with respect to transmission, which BPA can build without worrying about cost recovery, and transmission organization and squabbling between state and federal regulators. Nevertheless, the agency is vulnerable to the federal appropriations process, and we probably need to reach regional agreement on new ways for Northwest utilities to plan for and invest in transmission themselves.

We also need to recognize that the climate for new generation investments will never be very good in the Pacific Northwest, but we must nevertheless build in advance of dire need. BPA's footprint, theoretical statutory obligations, low average costs, and huge hydro variability make merchant construction risky and unpredictable. Public/private utility partnerships probably deserve consideration, especially with IOUs better able than Seattle to hedge gas price risks.